DECLARATION OF EMERGENCY

Department of Natural Resources
Office of Conservation

Statewide Orders No. 29-B and 29-B-a
(LAC 43:XIX.Chapters 2 and 11)

Order extending the deadline of drilling and completion operational and safety requirements for wells drilled in search or for the production of oil or natural gas at water locations

Pursuant to the power delegated under the laws of the state of Louisiana, and particularly title 30 of the Revised Statutes of 1950, as amended, and in conformity with the provisions of the Louisiana Administrative Procedure Act, title 49, sections 953(B)(1) and (2), 954(B)(2), as amended, the following Emergency Rule and reasons therefore are now adopted and promulgated by the commissioner of conservation as being necessary to protect the public health, safety and welfare of the people of the state of Louisiana, as well as the environment generally, by extending the effectiveness of the Emergency Rule this Rule supersedes the previous Emergency Rule for drilling and completion operational and safety requirements for wells drilled in search of oil and natural gas at water locations. The following Emergency Rule provides for commissioner of conservation approved exceptions to equipment requirements on workover operations. Furthermore, the extension of the rule allows more time to complete comprehensive rule amendments.

A. Need and Purpose for Emergency Rule

In light of the Gulf of Mexico Deepwater Horizon oil spill incident in federal waters approximately 50 miles off Louisiana’s coast and the threat posed to the natural resources of the state, and the economic livelihood and property of the citizens of the state caused thereby, the Office of Conservation began a review of its current drilling and completion operational and safety requirements for wells drilled in search of oil and natural gas at water locations. While the incidents of blowout of Louisiana wells is minimal, occurring at less than three-tenths of one percent of the wells drilled in Louisiana since 1987, the great risk posed by blowouts at water locations to the public health, safety and welfare of the people of the State, as well as the environment generally, necessitated the rule amendments contained herein.

After implementation of the Emergency Rule, conservation formed an ad hoc committee to further study comprehensive rulemaking in order to promulgate new permanent regulations which ensure increased operational and safety requirements for the drilling or completion of oil and gas wells at water locations within the state. Based upon the work of this ad hoc committee, draft proposed rules that would replace these emergency rules are being created for the consideration and comment by interested parties. This draft proposed Rule was published in the Potpourri section of the *Louisiana Register* on July 20, 2012. Rule promulgation is expected to continue with revised draft rules being published as a Notice of Intent within the next 60 days.

B. Synopsis of Emergency Rule

The Emergency Rule set forth hereinafter is intended to provide greater protection to the public health, safety and welfare of the people of the State, as well as the environment generally by extending the effectiveness of new operational and safety requirements for the drilling and completion of oil and gas wells at water locations. Following the Gulf of Mexico-Deepwater Horizon oil spill, the Office of Conservation ("conservation") investigated the possible expansion of Statewide Orders No. 29-B and 29-B-a requirements relating to well control at water locations. As part of the rule expansion project, Conservation reviewed the well control regulations of the U.S. Department of the Interior's mineral management service or MMS (now named the Bureau of Safety and Environmental Enforcement). Except in the instances where it was determined that the MMS provisions were repetitive of other provisions already being incorporated, were duplicative of existing conservation regulations or were not applicable to the situations encountered in Louisiana's waters, all provisions of the MMS regulations concerning well control issues at water locations were adopted by the preceding Emergency Rule, which this Rule supersedes, integrated into conservation's Statewide Orders No. 29-B and 29-B-a.

Conservation is currently performing a comprehensive review of its regulations as it considers future amendments to its operational rules and regulations found in Statewide Order No. 29-B and elsewhere. Specifically, the Emergency Rule extends the effectiveness of a new Chapter within Statewide Order No. 29-B (LAC 43:XIX.Chapter 2) to provide additional rules concerning the drilling and completion of oil and gas wells at water locations, specifically providing for the following: rig movement and reporting requirements, additional requirements for applications to drill, casing program requirements, mandatory diverter systems and blowout preventer requirements, oil and gas well-workover operations, diesel engine safety requirements, and drilling fluid regulations. Further, the Emergency Rule amends Statewide Order No. 29-B-a (LAC 43:XIX.Chapter 11) to provide for and expand upon rules concerning the required use of storm chokes in oil and gas wells at water locations.

C. Reasons

Recognizing the potential advantages of expanding the operational and safety requirements for the drilling and completion of oil and gas wells at water locations within the state, it has been determined that failure to establish such requirements in the form of an administrative rule may lead to the existence of an imminent peril to the public health, safety and welfare of the people of the state of Louisiana, as well as the environment generally. By this Rule conservation extends the effectiveness of the following requirements until such time as final comprehensive rules may be promulgated.

Protection of the public and our environment therefore requires the commissioner of conservation to extend the following rules in order to assure that drilling and completion of oil and gas wells at water locations within the state are undertaken in accordance with all reasonable care and protection to the health, safety of the public, oil and gas personnel and the environment generally. The Emergency Rule, amendment to Statewide Order No. 29-B (LAC 43:XIX.Chapter 2) and Statewide Order No. 29-B-a (LAC 43:XIXChapter 11) (“Emergency Rule”) set forth hereinafter are adopted and extended by the Office of Conservation.

D. Effective Date and Duration

1. The effective date for this Emergency Rule shall be February 10, 2014. This Emergency Rule is a continuation of the February 10, 2014 Emergency Rule.

2. The Emergency Rule herein adopted as a part thereof, shall remain effective for a period of not less than 120 days hereafter, or until the adoption of the final version of an amendment to Statewide Order No. 29-B and Statewide Order No. 29-B-a as noted herein, whichever occurs first.

The Emergency Rule signed by the commissioner on February 10, 2014 is hereby rescinded and replaced by the following Emergency Rule.

Title 43

NATURAL RESOURCES

Part XIX. Office of Conservation—General Operations

Subpart 1. Statewide Order No. 29-B

Chapter 2. Additional Requirements for Water Locations

§201. Applicability

A. In addition to the requirements set forth in Chapter 1 of this Subpart, all oil and gas wells being drilled or completed at a water location within the state and which are spud or on which workover operations commence on or after July 15, 2010 shall comply with this Chapter.

B. Unless otherwise stated herein, nothing within this Chapter shall alter the obligation of oil and gas operators to meet the requirements of Chapter 1 of this Subpart.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 40:

§203. Application to Drill

In addition to the requirements set forth in §103 of this Subpart, at the time of submittal of an application for permit to drill, the applicant will provide an electronic copy on a disk of the associated drilling rig's spill prevention control (SPC) plan that is required by DEQ pursuant to the provisions of Part IX of Title 33 of the *Louisiana Administrative Code* or any successor rule. Such plan shall become a part of the official well file. If the drilling rig to be used in drilling a permitted well changes between the date of the application and the date of drilling, the applicant shall provide an electronic copy on a disk of the SPC plan for the correct drilling rig within two business days of becoming aware of the change in rigs; but in no case shall the updated SPC plan be submitted after spudding of the well.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 40:

§204. Rig Movement and Reporting

A. The operator must report the movement of all drilling and workover rig units on and off locations to the appropriate district manager with the rig name, well serial number and expected time of arrival and departure.

B. Drilling operations on a platform with producing wells or other hydrocarbon flow must comply with the following.

1. An emergency shutdown station must be installed near the driller's console.

2. All producible wells located in the affected wellbay must be shut in below the surface and at the wellhead when:

a. a rig or related equipment is moved on and off a platform. This includes rigging up and rigging down activities within 500 feet of the affected platform;

b. a drilling unit is moved or skid between wells on a platform;

c. a mobile offshore drilling unit (MODU) moves within 500 feet of a platform.

3. Production may be resumed once the MODU is in place, secured, and ready to begin drilling operations.

C. The movement of rigs and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, shall be conducted in a safe manner. All wells in the same well-bay which are capable of producing hydrocarbons shall be shut in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving well-completion rigs and related equipment, unless otherwise approved by the district manager. A closed surface-controlled subsurface safety valve of the pump-through type may be used in lieu of the pump-through-type tubing plug, provided that the surface control has been locked out of operation. The well from which the rig or related equipment is to be moved shall also be equipped with a back-pressure valve prior to removing the blowout preventer (BOP) system and installing the tree.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 40:

§205. Casing Program

A. General Requirements

1. The operator shall case and cement all wells with a sufficient number of strings of casing and quantity and quality of cement in a manner necessary to prevent fluid migration in the wellbore, protect the underground source of drinking water (USDW) from contamination, support unconsolidated sediments, and otherwise provide a means of control of the formation pressures and fluids.

2. The operator shall install casing necessary to withstand collapse, bursting, tensile, and other stresses that may be encountered and the well shall be cemented in a manner which will anchor and support the casing. Safety factors in casing program design shall be of sufficient magnitude to provide optimum well control while drilling and to assure safe operations for the life of the well.

3. All tubulars and cement shall meet or exceed API standards. Cementing jobs shall be designed so that cement composition, placement techniques, and waiting times ensure that the cement placed behind the bottom 500 feet of casing attains a minimum compressive strength of 500 psi before drilling out of the casing or before commencing completion operations.

4. Centralizers

a. Surface casing shall be centralized by means of placing centralizers in the following manner.

i. A centralizer shall be placed on every third joint from the shoe to surface, with two centralizers being placed on each of the lowermost three joints of casing.

ii. If conductor pipe is set, three centralizers shall be equally spaced on surface casing to fall within the conductor pipe.

b. Intermediate and production casing, and drilling and production liners shall be centralized by means of a centralizer placed every third joint from the shoe to top of cement. Additionally, two centralizers shall be placed on each of the lowermost three joints of casing.

c. All centralizers shall meet API standards.

5. A copy of the documentation furnished by the manufacturer, if new, or supplier, if reconditioned, which certifies tubular condition, shall be provided with the well history and work resume report (Form WH-1).

B. Conductor Pipe. A conductor pipe is that pipe ordinarily used for the purpose of supporting unconsolidated surface deposits. A conductor pipe shall be used during the drilling of any oil and gas well and shall be set at depth that allows use of a diverter system.

C. Surface Casing

1. Where no danger of pollution of the USDW exists, the minimum amount of surface ~~of~~ or first-intermediate casing to be set shall be determined from Table 1 hereof, except that in no case shall less surface casing be set than an amount needed to protect the USDW unless an alternative method of USDW protection is approved by the district manager.

Table 1		
Total Depth of Contact	Casing Required	Surface Casing Test Pressure (lbs. per sq. in.)
0-2500	100	300
2500-3000	150	600
3000-4000	300	600
4000-5000	400	600
5000-6000	500	750
6000-7000	800	1000
7000-8000	1000	1000
8000-9000	1400	1000
9000-Deeper	1800	1000

a. In known low-pressure areas, exceptions to the above may be granted by the commissioner or his agent. If, however, in the opinion of the commissioner, or his agent, the above regulations shall be found inadequate, and additional or lesser amount of surface casing and/or test pressure shall be required for the purpose of safety and the protection of the USDW.

2. Surface casing shall be cemented with a sufficient volume of cement to insure cement returns to the surface.

3. Surface casing shall be tested before drilling the plug by applying a minimum pump pressure as set forth in Table 1 after at least 200 feet of the mud-laden fluid has been displaced with water at the top of the column. If at the end of 30 minutes the pressure gauge shows a drop of 10 percent of test pressure as outlined in Table 1, the operator shall be required to take such corrective measures as will insure that such surface casing will hold said pressure for 30 minutes without a drop of more than 10 percent of the test pressure. The provisions of Paragraph E.7 below, for the producing casing, shall also apply to the surface casing.

4. Cement shall be allowed to stand a minimum of 12 hours under pressure before initiating test or drilling plug. Under pressure is complied with if one float valve is used or if pressure is held otherwise.

D. Intermediate Casing/Drilling Liner

1. Intermediate casing is that casing used as protection against caving of heaving formations or when other means are not adequate for the purpose of segregating upper oil, gas or water-bearing strata. Intermediate casing/drilling liner shall be set when required by abnormal pressure or other well conditions.

2. If an intermediate casing string is deemed necessary by the district manager for the prevention of underground waste, such regulations pertaining to a minimum setting depth, quality of casing, and cementing and testing of sand, shall be determined by the Office of Conservation after due hearing. The provisions of Paragraph E.7 below, for the producing casing, shall also apply to the intermediate casing.

3. Intermediate casing/drilling liner shall be at minimum, cemented in such a manner, at least 500 feet above all known hydrocarbon bearing formations to insure isolation and, if applicable, all abnormal pressure formations are isolated from normal pressure formations, but in no case shall less cement be used than the amount necessary to fill the casing/liner annulus to a point 500 feet above the shoe or the top of the liner whichever is less. If a liner is used as an intermediate string, the cement shall be tested by a fluid entry test (-0.5 ppg EMW) to determine whether a seal between the liner top and next larger casing string has been achieved, and the liner-lap point must be at least 300 feet above the previous casing shoe. The drilling liner (and liner-lap) shall be tested to a pressure at least equal to the anticipated pressure to which the liner will be subjected to during the formation-integrity test below that liner shoe, or subsequent liner shoes if set. Testing shall be in accordance with Subsection G below.

4. Before drilling the plug in the intermediate string of casing, the casing shall be tested by pump pressure, as determined from Table 2 hereof, after 200 feet of mud-laden fluid in the casing has been displaced by water at the top of the column.

Table 2. Intermediate Casing and Liner	
Depth Set	Test Pressure (lbs. per sq. in.)
2000-3000'	800
3000-6000'	1000
6000-9000'	1200
9000-and deeper	1500

a. If at the end of 30 minutes the pressure gauge shows a drop of 10 percent of the test pressure or more, the operator shall be required to take such corrective measures as will insure that casing is so set and cemented that it will hold said pressure for 30 minutes without a drop of more than 10 percent of the test pressure on the gauge.

5. Cement shall be allowed to stand a minimum of 12 hours under pressure and a minimum total of 24 hours before initiating pressure test. Under pressure is complied with if one or more float valves are employed and are shown to be holding the cement in place, or when other means of holding pressure is used. When an operator elects to perforate and squeeze or to cement around the shoe, he may proceed with such work after 12 hours have elapsed after placing the first cement.

6. If the test is unsatisfactory, the operator shall not proceed with the drilling of the well until a satisfactory test has been obtained.

E. Producing String

1. Producing string, production casing or production liner is that casing used for the purpose of segregating the horizon from which production is obtained and affording a means of communication between such horizons and the surface.

2. The producing string of casing shall consist of new or reconditioned casing, tested at mill test pressure or as otherwise designated by the Office of Conservation.

3. Cement shall be by the pump-and-plug method, or another method approved by the Office of Conservation. Production casing/production liner shall be at minimum, cemented in such a manner, at least 500 feet above all known hydrocarbon bearing formations to insure isolation and, if applicable, all abnormal pressure formations are isolated from normal pressure formations, but in no case shall less cement be used than the amount necessary to fill the casing/liner annulus to a point 500 feet above the shoe or the top of the liner whichever is less. If a liner is used as a producing string, the cement shall be tested by a fluid entry test (-0.5 ppg EMW) to determine whether a seal between the liner top and next larger casing string has been achieved, and the liner-lap point must be at least 300 feet above the previous casing shoe. The production liner (and liner-lap) shall be tested to a pressure at least equal to the anticipated pressure to which the liner will be subjected to during the formation-integrity test below that liner shoe, or subsequent liner shoes if set. Testing shall be in accordance with Subsection G below.

4. The amount of cement to be left remaining in the casing, until the requirements of Paragraph 5 below have been met, shall be not less than 20 feet. This shall be accomplished through the use of a float-collar, or other approved or practicable means, unless a full-hole cementer, or its equivalent, is used.

5. Cement shall be allowed to stand a minimum of 12 hours under pressure and a minimum total of 24 hours before initiating pressure test in the producing or oil string. Under pressure is complied with if one or more float valves are employed and are shown to be holding the cement in place, or when other means of holding pressure is used. When an operator elects to perforate and squeeze or to cement around the shoe, he may proceed with such work after 12 hours have elapsed after placing the first cement.

6. Before drilling the plug in the producing string of casing, the casing shall be tested by pump pressure, as determined from Table 3 hereof, after 200 feet of mud-laden fluid in the casing has been displaced by water at the top of the column.

Table 3. Producing String	
Depth Set	Test Pressure (lbs. per sq. in.)
2000-3000'	800
3000-6000'	1000
6000-9000'	1200
9000-and deeper	1500

a. If at the end of 30 minutes the pressure gauge shows a drop of 10 percent of the test pressure or more, the operator shall be required to take such corrective measures as will insure that the producing string of casing is so set and cemented that it will hold said pressure for 30 minutes without a drop of more than 10 percent of the test pressure on the gauge.

7. If the commissioner's agent is not present at the time designated by the operator for inspection of the casing tests of the producing string, the operator shall have such tests witnessed, preferably by an offset operator. An affidavit of test, on the form prescribed by the district office, signed by the operator and witness, shall be furnished to the district office showing that the test conformed satisfactorily to the above mentioned regulations before proceeding with the completion. If test is satisfactory, normal operations may be resumed immediately.

8. If the test is unsatisfactory, the operator shall not proceed with the completion of the well until a satisfactory test has been obtained.

F. Cement Evaluation

1. Cement evaluation tests (cement bond or temperature survey) shall be conducted for all casing and liners installed below surface casing to assure compliance with LAC 43:XIX.205.D.3 and E.3.

2. Remedial cementing operations that are required to achieve compliance with LAC 43:XIX.205.D.3 and E.3 shall be conducted following receipt of an approved work permit from the district manager for the proposed operations.

3. Cementing and wireline records demonstrating the presence of the required cement tops shall be retained by the operator for a period of two years.

G. Leak-off Tests

1. A pressure integrity test must be conducted below the surface casing or liner and all intermediate casings or liners. The district manager may require a pressure-integrity test at the conductor casing shoe if warranted by local geologic conditions or the planned casing setting depth. Each pressure integrity test must be conducted after drilling at least 10 feet but no more than 50 feet of new hole below the casing shoe and must be tested to either the formation leak-off pressure or to the anticipated equivalent drilling fluid weight at the setting depth of the next casing string.

a. The pressure integrity test and related hole-behavior observations, such as pore-pressure test results, gas-cut drilling fluid, and well kicks must be used to adjust the drilling fluid program and the setting depth of the next casing string. All test results must be recorded and hole-behavior observations made during the course of drilling related to formation integrity and pore pressure in the driller's report.

b. While drilling, a safe drilling margin must be maintained. When this safe margin cannot be maintained, drilling operations must be suspended until the situation is remedied.

H. Prolonged Drilling Operations

1. If wellbore operations continue for more than 30 days within a casing string run to the surface:

a. drilling operations must be stopped as soon as practicable, and the effects of the prolonged operations on continued drilling operations and the life of the well evaluated. At a minimum, the operator shall:

i. caliper or pressure test the casing; and

ii. report evaluation results to the district manager and obtain approval of those results before resuming operations.

b. If casing integrity as determined by the evaluation has deteriorated to a level below minimum safety factors, the casing must be repaired or another casing string run. Approval from the district manager shall be obtained prior to any casing repair activity.

I. Tubing and Completion

1. Well-completion operations means the work conducted to establish the production of a well after the production-casing string has been set, cemented, and pressure-tested.

2. Prior to engaging in well-completion operations, crew members shall be instructed in the safety requirements of the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment. Date and time of safety meetings shall be recorded and available for review by the Office of Conservation.

3. When well-completion operations are conducted on a platform where there are other hydrocarbon-producing wells or other hydrocarbon flow, an emergency shutdown system (ESD) manually controlled station shall be installed near the driller's console or well-servicing unit operator's work station.

4. No tubing string shall be placed in service or continue to be used unless such tubing string has the necessary strength and pressure integrity and is otherwise suitable for its intended use.

5. A valve, or its equivalent, tested to a pressure of not less than the calculated bottomhole pressure of the well, shall be installed below any and all tubing outlet connections.

6. When a well develops a casing pressure, upon completion, equivalent to more than three-quarters of the internal pressure that will develop the minimum yield point of the casing, such well shall be required by the district manager to be killed, and a tubing packer to be set so as to keep such excessive pressure off of the casing.

7. Wellhead Connections. Wellhead connections shall be tested prior to installation at a pressure indicated by the district manager in conformance with conditions existing in areas in which they are used. Whenever such tests are made in the field, they shall be witnessed by an agent of the Office of Conservation. Tubing and tubingheads shall be free from obstructions in wells used for bottomhole pressure test purposes.

8. When the tree is installed, the wellhead shall be equipped so that all annuli can be monitored for sustained pressure. If sustained casing pressure is observed on a well, the operator shall immediately notify the district manager.

9. Wellhead, tree, and related equipment shall have a pressure rating greater than the shut-in tubing pressure and shall be designed, installed, used, maintained, and tested so as to achieve and maintain pressure control. New wells completed as flowing or gas-lift wells shall be equipped with a minimum of one master valve and one surface safety valve, installed above the master valve, in the vertical run of the tree.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 40:

§207. Diverter Systems and Blowout Preventers

A. Diverter System. A diverter system shall be required when drilling surface hole in areas where drilling hazards are known or anticipated to exist. The district manager may, at his discretion, require the use of a diverter system on any well. In cases where it is required, a diverter system consisting of a diverter sealing element, diverter lines, and control systems must be designed, installed, used, maintained, and tested to ensure proper diversion of gases, water, drilling fluids, and other materials away from facilities and personnel. The diverter system shall be designed to incorporate the following elements and characteristics:

1. dual diverter lines arranged to provide for maximum diversion capability;

2. at least two diverter control stations. One station shall be on the drilling floor. The other station shall be in a readily accessible location away from the drilling floor;

3. remote-controlled valves in the diverter lines. All valves in the diverter system shall be full-opening. Installation of manual or butterfly valves in any part of the diverter system is prohibited;

4. minimize the number of turns in the diverter lines, maximize the radius of curvature of turns, and minimize or eliminate all right angles and sharp turns;

5. anchor and support systems to prevent whipping and vibration;

6. rigid piping for diverter lines. The use of flexible hoses with integral end couplings in lieu of rigid piping for diverter lines shall be approved by the district manager.

B. Diverter Testing Requirements

1. When the diverter system is installed, the diverter components including the sealing element, diverter valves, control systems, stations and vent lines shall be function and pressure tested.

2. For drilling operations with a surface wellhead configuration, the system shall be function tested at least once every 24-hour period after the initial test.

3. After nippling-up on conductor casing, the diverter sealing element and diverter valves are to be pressure tested to a minimum of 200 psig. Subsequent pressure tests are to be conducted within seven days after the previous test.

4. Function tests and pressure tests shall be alternated between control stations.

5. Recordkeeping Requirements

a. Pressure and function tests are to be recorded in the driller's report and certified (signed and dated) by the operator's representative.

b. The control station used during a function or pressure test is to be recorded in the driller's report.

c. Problems or irregularities during the tests are to be recorded along with actions taken to remedy same in the driller's report.

d. All reports pertaining to diverter function and/or pressure tests are to be retained for inspection at the wellsite for the duration of drilling operations.

C. BOP Systems. The operator shall specify and insure that contractors design, install, use, maintain and test the BOP system to ensure well control during drilling, workover and all other appropriate operations. The surface BOP stack shall be installed before drilling below surface casing.

1. BOP system components for drilling activity located over a body of water shall be designed and utilized, as necessary, to control the well under all potential conditions that might occur during the operations being conducted and at minimum, shall include the following components:

a. annular-type well control component;

b. hydraulically-operated blind rams;

c. hydraulically-operated shear rams;

d. two sets of hydraulically-operated pipe rams.

2. Drilling activity with a tapered drill string shall require the installation of two or more sets of conventional or variable-bore pipe rams in the BOP stack to provide, at minimum, two sets of rams capable of sealing around the larger-size drill string and one set of pipe rams capable of sealing around the smaller-size drill string.

3. A set of hydraulically-operated combination rams may be used for the blind rams and shear rams.

4. All connections used in the surface BOP system must be flanged, including the connections between the well control stack and the first full-opening valve on the choke line and the kill line.

5. The commissioner of conservation, following a public hearing, may grant exceptions to the requirements of LAC 43:XIX.207.C-J.

D. BOP Working Pressure. The working pressure rating of any BOP component, excluding annular-type preventers, shall exceed the maximum anticipated surface pressure (MASP) to which it may be subjected.

E. BOP Auxiliary Equipment. All BOP systems shall be equipped and provided with the following.

1. A hydraulically actuated accumulator system which shall provide 1.5 times volume of fluid capacity to close and hold closed all BOP components, with a minimum pressure of 200 psig above the pre-charge pressure without assistance from a charging system.

2. A backup to the primary accumulator-charging system, supplied by a power source independent from the power source to the primary, which shall be sufficient to close all BOP components and hold them closed.

3. Accumulator regulators supplied by rig air without a secondary source of pneumatic supply shall be equipped with manual overrides or other devices to ensure capability of hydraulic operation if the rig air is lost.

4. At least one operable remote BOP control station in addition to the one on the drilling floor. This control station shall be in a readily accessible location away from the drilling floor. If a BOP control station does not perform properly, operations shall be suspended until that station is operable.

5. A drilling spool with side outlets, if side outlets are not provided in the body of the BOP stack, to provide for separate kill and choke lines.

6. A kill line and a separate choke line are required. Each line must be equipped with two full-opening valves and at least one of the valves must be remotely controlled. The choke line shall be installed above the bottom ram. A manual valve must be used instead of the remotely controlled valve on the kill line if a check valve is installed between the two full-opening manual valves and the pump or manifold. The valves must have a working pressure rating equal to or greater than the working pressure rating of the connection to which they are attached, and must be installed between the well control stack and the choke or kill line. For operations with expected surface pressures greater than 3,500 psi, the kill line must be connected to a pump or manifold. The kill line inlet on the BOP stack must not be used for taking fluid returns from the wellbore.

7. A valve installed below the swivel (upper kelly cock), essentially full-opening, and a similar valve installed at the bottom of the kelly (lower kelly cock). An operator must be able to strip the lower kelly cock through the BOP stack. A wrench to fit each valve shall be stored in a location readily accessible to the drilling crew. If drilling with a mud motor and utilizing drill pipe in lieu of a kelly, you must install one kelly valve above, and one strippable kelly valve below the joint of pipe used in place of a kelly. On a top-drive system equipped with a remote-controlled valve, you must install a strippable kelly-type valve below the remote-controlled valve.

8. An essentially full-opening drill-string safety valve in the open position on the rig floor shall be available at all times while drilling operations are being conducted. This valve shall be maintained on the rig floor to fit all connections that are in the drill string. A wrench to fit the drill-string safety valve shall be stored in a location readily accessible to the drilling crew.

9. A safety valve shall be available on the rig floor assembled with the proper connection to fit the casing string being run in the hole.

10. Locking devices installed on the ram-type preventers.

F. BOP Maintenance and Testing Requirements

1. The BOP system shall be visually inspected on a daily basis.

2. Pressure tests (low and high pressure) of the BOP system are to be conducted at the following times and intervals:

a. during a shop test prior to transport of the BOPs to the drilling location. Shop tests are not required for equipment that is transported directly from one well location to another;

b. immediately following installation of the BOPs;

c. within 14 days of the previous BOP pressure test, alternating between control stations and at a staggered interval to allow each crew to operate the equipment. If either control system is not functional, further operations shall be suspended until the nonfunctional, system is operable. Exceptions may be granted by the district manager in cases where a trip is scheduled to occur within 2 days after the 14-day testing deadline;

d. before drilling out each string of casing or liner (The district manager may require that a conservation enforcement specialist witness the test prior to drilling out each casing string or liner.);

e. Not more than 48 hours before a well is drilled to a depth that is within 1000 feet of a hydrogen sulfide zone (The district manager may require that a conservation enforcement specialist witness the test prior to drilling to a depth that is within 1000 feet of a hydrogen sulfide zone.);

f. when the BOP tests are postponed due to well control problem(s), the BOP test is to be performed on the first trip out of the hole, and reasons for postponing the testing are to be recorded in the driller's report.

3. Low pressure tests (200-300 psig) of the BOP system (choke manifold, kelly valves, drill-string safety valves, etc.) are to be performed at the times and intervals specified in LAC 43:XIX.207.F.2. in accordance with the following provisions.

a. Test pressures are to be held for a minimum of five minutes.

b. Variable bore pipe rams are to be tested against the largest and smallest sizes of pipe in use, excluding drill collars and bottom hole assembly.

c. Bonnet seals are to be tested before running the casing when casing rams are installed in the BOP stack.

4. High pressure tests of the BOP system are to be performed at the times and intervals specified in LAC 43:XIX.207.F.2 in accordance with the following provisions.

a. Test pressures are to be held for a minimum of five minutes.

b. Ram-type BOP's, choke manifolds, and associated equipment are to be tested to the rated working pressure of the equipment or 500 psi greater than the calculated MASP for the applicable section of the hole.

c. Annular-type BOPs are to be tested to 70 percent of the rated working pressure of the equipment.

5. The annular and ram-type BOPs with the exception of the blind-shear rams are to be function tested every seven days between pressure tests. All BOP test records should be certified (signed and dated) by the operator's representative.

a. Blind-shear rams are to be tested at all casing points and at an interval not to exceed 30 days.

6. If the BOP equipment does not hold the required pressure during a test, the problem must be remedied and a retest of the affected component(s) performed. Additional BOP testing requirements:

a. use water to test the surface bop system;

b. if a control station is not functional operations shall be suspended until that station is operable;

c. test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly.

G. BOP Record Keeping. The time, date and results of pressure tests, function tests, and inspections of the BOP system are to be recorded in the driller's report. All pressure tests shall be recorded on an analog chart or digital recorder. All documents are to be retained for inspection at the wellsite for the duration of drilling operations and are to be retained in the operator's files for a period of two years.

H. BOP Well Control Drills. Weekly well control drills with each drilling crew are to be conducted during a period of activity that minimizes the risk to drilling operations. The drills must cover a range of drilling operations, including drilling with a diverter (if applicable), on-bottom drilling, and tripping. Each drill must be recorded in the driller's report and is to include the time required to close the BOP system, as well as, the total time to complete the entire drill.

I. Well Control Safety Training. In order to ensure that all drilling personnel understand and can properly perform their duties prior to drilling wells which are subject to the jurisdiction of the Office of Conservation, the operator shall require that contract drilling companies provide and/or implement the following:

1. periodic training for drilling contractor employees which ensures that employees maintain an understanding of, and competency in, well control practices;

2. procedures to verify adequate retention of the knowledge and skills that the contract drilling employees need to perform their assigned well control duties.

J. Well Control Operations

1. The operator must take necessary precautions to keep wells under control at all times and must:

a. use the best available and safest drilling technology to monitor and evaluate well conditions and to minimize the potential for the well to flow or kick;

b. have a person onsite during drilling operations who represents the operators interests and can fulfill the operators responsibilities;

c. ensure that the tool pusher, operator's representative, or a member of the drilling crew maintains continuous surveillance on the rig floor from the beginning of drilling operations until the well is completed or abandoned, unless you have secured the well with blowout preventers (BOPs), bridge plugs, cement plugs, or packers;

d. use and maintain equipment and materials necessary to ensure the safety and protection of personnel, equipment, natural resources, and the environment.

2. Whenever drilling operations are interrupted, a downhole safety device must be installed, such as a cement plug, bridge plug, or packer. The device must be installed at an appropriate depth within a properly cemented casing string or liner.

a. Among the events that may cause interruption to drilling operations are:

i. evacuation of the drilling crew;

ii. inability to keep the drilling rig on location; or

iii. repair to major drilling or well-control equipment.

3. If the diverter or BOP stack is nippled down while waiting on cement, it must be determined, before nippling down, when it will be safe to do so based on knowledge of formation conditions, cement composition, effects of nippling down, presence of potential drilling hazards, well conditions during drilling, cementing, and post cementing, as well as past experience.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 40:

§209. Casing-Heads

A. All wells shall be equipped with casing-heads with a test pressure in conformance with conditions existing in areas in which they are used. Casing-head body, as soon as installed shall be equipped with proper connections and valves accessible to the surface. Reconditioning shall be required on any well showing pressure on the casing-head, or leaking gas or oil between the oil string and next larger size casing string, when, in the opinion of the district managers, such pressure or leakage assume hazardous proportions or indicate the existence of underground waste. Mud-laden fluid may be pumped between any two strings of casing at the top of the hole, but no cement shall be used except by special permission of the commissioner or his agent.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 40:

§211. Oil and Gas Well-Workover Operations

A. Definitions. When used in this Section, the following terms shall have the meanings given below.

Expected Surface Pressure—the highest pressure predicted to be exerted upon the surface of a well. In calculating expected surface pressure, reservoir pressure as well as applied surface pressure must be considered.

Routine Operations—any of the following operations conducted on a well with the tree installed including cutting paraffin, removing and setting pump-through-type tubing plugs, gas-lift valves, and subsurface safety valves which can be removed by wireline operations, bailing sand, pressure surveys, swabbing, scale or corrosion treatment, caliper and gauge surveys, corrosion inhibitor treatment, removing or replacing subsurface pumps, through-tubing logging, wireline fishing, and setting and retrieving other subsurface flow-control devices.

Workover Operations—the work conducted on wells after the initial completion for the purpose of maintaining or restoring the productivity of a well.

B. When well-workover operations are conducted on a well with the tree removed, an emergency shutdown system (ESD) manually controlled station shall be installed near the driller's console or well-servicing unit operator's work station, except when there is no other hydrocarbon-producing well or other hydrocarbon flow on the platform.

C. Prior to engaging in well-workover operations, crew members shall be instructed in the safety requirements of the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment. Date and time of safety meetings shall be recorded and available for review.

D. Well-control fluids, equipment, and operations. The following requirements apply during all well-workover operations with the tree removed.

1. The minimum BOP-system components when the expected surface pressure is less than or equal to 5,000 psi shall include one annular-type well control component, one set of pipe rams, and one set of blind-shear rams. The shear ram component of this requirement shall be effective for any workover operations initiated on or after January 1, 2011 and not before.

2. The minimum BOP-system components when the expected surface pressure is greater than 5,000 psi shall include one annular-type well control component, two sets of pipe rams, and one set of blind-shear rams. The shear ram component of this requirement shall be effective for any workover operations initiated on or after January 1, 2011 and not before.

3. BOP auxillary equipment in accordance with the requirements of LAC 43:XIX.207.E.

4. When coming out of the hole with drill pipe or a workover string, the annulus shall be filled with well-control fluid before the change in such fluid level decreases the hydrostatic pressure 75 pounds per square inch (psi) or every five stands of drill pipe or workover string, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe or workover string and drill collars that may be pulled prior to filling the hole and the equivalent well-control fluid volume shall be calculated and posted near the operator's station. A mechanical, volumetric, or electronic device for measuring the amount of well-control fluid required to fill the hold shall be utilized.

5. The following well-control-fluid equipment shall be installed, maintained, and utilized:

a. a fill-up line above the uppermost BOP;

b. a well-control, fluid-volume measuring device for determining fluid volumes when filling the hole on trips; and

c. a recording mud-pit-level indicator to determine mud-pit-volume gains and losses. This indicator shall include both a visual and an audible warning device.

E. The minimum BOP-system components for well-workover operations with the tree in place and performed through the wellhead inside of conventional tubing using small-diameter jointed pipe (usually 3/4 inch to 1 1/4 inch) as a work string, i.e., small-tubing operations, shall include two sets of pipe rams, and one set of blind rams.

1. An essentially full-opening work-string safety valve in the open position on the rig floor shall be available at all times while well-workover operations are being conducted. This valve shall be maintained on the rig floor to fit all connections that are in the work string. A wrench to fit the work-string safety valve shall be stored in a location readily accessible to the workover crew.

F. For coiled tubing operations with the production tree in place, you must meet the following minimum requirements for the BOP system:

1. BOP system components must be in the following order from the top down when expected surface pressures are less than or equal to 3,500 psi:

a. stripper or annular-type well control component;

b. hydraulically-operated blind rams;

c. hydraulically-operated shear rams;

d. kill line inlet;

e. hydraulically operated two-way slip rams;

f. hydraulically operated pipe rams.

2. BOP system components must be in the following order from the top down when expected surface pressures are greater than 3,500 psi:

a. stripper or annular-type well control component;

b. hydraulically-operated blind rams;

c. hydraulically-operated shear rams;

d. kill line inlet;

e. hydraulically-operated two-way slip rams;

f. hydraulically-operated pipe rams;

g. hydraulically-operated blind-shear rams. These rams should be located as close to the tree as practical.

3. BOP system components must be in the following order from the top down for wells with returns taken through an outlet on the BOP stack:

a. stripper or annular-type well control component;

b. hydraulically-operated blind rams;

c. hydraulically-operated shear rams;

d. kill line inlet;

e. hydraulically-operated two-way slip rams;

f. hydraulically-operated pipe rams;

g. a flow tee or cross;

h. hydraulically-operated pipe rams;

i. hydraulically-operated blind-shear rams on wells with surface pressures less than or equal to 3,500 psi. As an option, the pipe rams can be placed below the blind-shear rams. The blind-shear rams should be placed as close to the tree as practical.

4. A set of hydraulically-operated combination rams may be used for the blind rams and shear rams.

5. A set of hydraulically-operated combination rams may be used for the hydraulic two-way slip rams and the hydraulically-operated pipe rams.

6. A dual check valve assembly must be attached to the coiled tubing connector at the downhole end of the coiled tubing string for all coiled tubing well-workover operations. To conduct operations without a downhole check valve, it must be approved by the district manager.

7. A kill line and a separate choke line are required. Each line must be equipped with two full-opening valves and at least one of the valves must be remotely controlled. A manual valve must be used instead of the remotely controlled valve on the kill line if a check valve is installed between the two full-opening manual valves and the pump or manifold. The valves must have a working pressure rating equal to or greater than the working pressure rating of the connection to which they are attached, and must be installed between the well control stack and the choke or kill line. For operations with expected surface pressures greater than 3,500 psi, the kill line must be connected to a pump or

manifold. The kill line inlet on the BOP stack must not be used for taking fluid returns from the wellbore.

8. The hydraulic-actuating system must provide sufficient accumulator capacity to close-open-close each component in the BOP stack. This cycle must be completed with at least 200 psi above the pre-charge pressure without assistance from a charging system.

9. All connections used in the surface BOP system from the tree to the uppermost required ram must be flanged, including the connections between the well control stack and the first full-opening valve on the choke line and the kill line.

10. The coiled tubing connector must be tested to a low pressure of 200 to 300 psi, followed by a high pressure test to the rated working pressure of the connector or the expected surface pressure, whichever is less. The dual check valves must be successfully pressure tested to the rated working pressure of the connector, the rated working pressure of the dual check valve, expected surface pressure, or the collapse pressure of the coiled tubing, whichever is less.

G. The minimum BOP-system components for well-workover operations with the tree in place and performed by moving tubing or drill pipe in or out of a well under pressure utilizing equipment specifically designed for that purpose, i.e., snubbing operations, shall include the following:

1. one set of pipe rams hydraulically operated; and

2. two sets of stripper-type pipe rams hydraulically operated with spacer spool.

H. Test pressures must be recorded during BOP and coiled tubing tests on a pressure chart, or with a digital recorder, unless otherwise approved by the district manager. The test interval for each BOP system component must be 5 minutes, except for coiled tubing operations, which must include a 10 minute high-pressure test for the coiled tubing string.

I. Wireline Operations. The operator shall comply with the following requirements during routine, as defined in Subsection A of this section, and nonroutine wireline workover operations:

1. Wireline operations shall be conducted so as to minimize leakage of well fluids. Any leakage that does occur shall be contained to prevent pollution.

2. All wireline perforating operations and all other wireline operations where communication exists between the completed hydrocarbon-bearing zone(s) and the wellbore shall use a lubricator assembly containing at least one wireline valve.

3. When the lubricator is initially installed on the well, it shall be successfully pressure tested to the expected shut-in surface pressure.

J. Following completion of the well-workover activity, all such records shall be retained by the operator for a period of two years.

K. An essentially full-opening work-string safety valve in the open position on the rig floor shall be available at all times while well-workover operations are being conducted. This valve shall be maintained on the rig floor to fit all connections that are in the work string. A wrench to fit the work-string safety valve shall be stored in a location readily accessible to the workover crew.

L. The commissioner may grant an exception to any provisions of this section that require specific equipment upon proof of good cause. For consideration of an exception, the operator must show proof of the unavailability of properly sized equipment and demonstrate that anticipated surface pressures minimize the potential for a loss of well control during the proposed operations. All exception requests must be made in writing to the commissioner and include documentation of any available evidence supporting the request.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 40:

§213. Diesel Engine Safety Requirements

A. On or after January 1, 2011, each diesel engine with an air take device must be equipped to shut down the diesel engine in the event of a runaway.

1. A diesel engine that is not continuously manned, must be equipped with an automatic shutdown device.

2. A diesel engine that is continuously manned, may be equipped with either an automatic or remote manual air intake shutdown device.

3. A diesel engine does not have to be equipped with an air intake device if it meets one of the following criteria:

a. starts a larger engine;

b. powers a firewater pump;

c. powers an emergency generator;

d. powers a bop accumulator system;

e. provides air supply to divers or confined entry personnel;

f. powers temporary equipment on a nonproducing platform;

g. powers an escape capsule; or

h. powers a portable single-cylinder rig washer.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 40:

§215. Drilling Fluids

A. The inspectors and engineers of the Office of Conservation shall have access to the mud records of any drilling well, except those records which pertain to special muds and special work with respect to patentable rights, and shall be allowed to conduct any essential test or tests on the mud used in the drilling of a well. When the conditions and tests indicate a need for a change in the mud or drilling fluid program in order to insure proper control of the well, the district manager shall require the operator or company to use due diligence in correcting any objectionable conditions.

B. Well-control fluids, equipment, and operations shall be designed, utilized, maintained, and/or tested as necessary to control the well in foreseeable conditions and circumstances.

C. The well shall be continuously monitored during all operations and shall not be left unattended at any time unless the well is shut in and secured.

D. The following well-control-fluid equipment shall be installed, maintained, and utilized:

1. a fill-up line above the uppermost BOP;

2. a well-control, fluid-volume measuring device for determining fluid volumes when filling the hole on trips; and

3. a recording mud-pit-level indicator to determine mud-pit-volume gains and losses. This indicator shall include both a visual and an audible warning device.

E. Safe Practices

1. Before starting out of the hole with drill pipe, the drilling fluid must be properly conditioned. A volume of drilling fluid equal to the annular volume must be circulated with the drill pipe just off-bottom. This practice may be omitted if documentation in the driller's report shows:

a. No indication of formation fluid influx before starting to pull the drill pipe from the hole;

b. The weight of returning drilling fluid is within 0.2 pounds per gallon of the drilling fluid entering the hole;

2. Record each time drilling fluid is circulated in the hole in the driller’s report.

3. When coming out of the hole with drill pipe, the annulus must be filled with drilling fluid before the hydrostatic pressure decreases by 75 psi, or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe and drill collars that may be pulled must be calculated before the hole is filled. Both sets of numbers must be posted near the driller's station. A mechanical, volumetric, or electronic device must be used to measure the drilling fluid required to fill the hole.

4. Controlled rates must be used to run and pull drill pipe and downhole tools so as not to swab or surge the well.

5. When there is an indication of swabbing or influx of formation fluids, appropriate measures must be taken to control the well. Circulate and condition the well, on or near-bottom, unless well or drilling-fluid conditions prevent running the drill pipe back to the bottom.

6. The maximum pressures must be calculated and posted near the driller's console that you may safely contain under a shut-in BOP for each casing string. The pressures posted must consider the surface pressure at which the formation at the shoe would break down, the rated working pressure of the BOP stack, and 70 percent of casing burst (or casing test as approved by the district manager). As a minimum, you must post the following two pressures:

a. the surface pressure at which the shoe would break down. This calculation must consider the current drilling fluid weight in the hole; and

b. the lesser of the BOP's rated working pressure or 70 percent of casing-burst pressure (or casing test otherwise approved by the district manager).

7. An operable drilling fluid-gas separator and degasser must be installed before you begin drilling operations. This equipment must be maintained throughout the drilling of the well.

8. The test fluids in the hole must be circulated or reverse circulated before pulling drill-stem test tools from the hole. If circulating out test fluids is not feasible, with an appropriate kill weight fluid test fluids may be bullhead out of the drill-stem test string and tools.

9. When circulating, the drilling fluid must be tested at least once each work shift or more frequently if conditions warrant. The tests must conform to industry-accepted practices and include density, viscosity, and gel strength; hydrogen ion concentration; filtration; and any other tests the district manager requires for monitoring and maintaining drilling fluid quality, prevention of downhole equipment problems and for kick detection. The test results must be recorded in the drilling fluid report.

F. Monitoring Drilling Fluids

1. Once drilling fluid returns are established, the following drilling fluid-system monitoring equipment must be installed throughout subsequent drilling operations. This equipment must have the following indicators on the rig floor:

a. pit level indicator to determine drilling fluid-pit volume gains and losses. This indicator must include both a visual and an audible warning device;

b. volume measuring device to accurately determine drilling fluid volumes required to fill the hole on trips;

c. return indicator devices that indicate the relationship between drilling fluid-return flow rate and pump discharge rate. This indicator must include both a visual and an audible warning device; and

d. gas-detecting equipment to monitor the drilling fluid returns. The indicator may be located in the drilling fluid-logging compartment or on the rig floor. If the indicators are only in the logging compartment, you must continually man the equipment and have a means of immediate communication with the rig floor. If the indicators are on the rig floor only, an audible alarm must be installed.

G. Drilling Fluid Quantities

1. Quantities of drilling fluid and drilling fluid materials must be maintained and replenished at the drill site as necessary to ensure well control. These quantities must be determined based on known or anticipated drilling conditions, rig storage capacity, weather conditions, and estimated time for delivery.

2. The daily inventories of drilling fluid and drilling fluid materials must be recorded, including weight materials and additives in the drilling fluid report.

3. If there are not sufficient quantities of drilling fluid and drilling fluid material to maintain well control, the drilling operations must be suspended.

H. Drilling Fluid-Handling Areas

1. Drilling fluid-handling areas must be classified according to API RP 500, recommended practice for classification of locations for electrical installations at petroleum facilities, classified as class I, division 1 and division 2 or API RP 505, recommended practice for classification of locations for electrical installations at petroleum facilities, classified as class 1, zone 0, zone 1, and zone 2. In areas where dangerous concentrations of combustible gas may accumulate. A ventilation system and gas monitors must be installed and maintained. Drilling fluid-handling areas must have the following safety equipment:

a. a ventilation system capable of replacing the air once every 5 minutes or 1.0 cubic feet of air-volume flow per minute, per square foot of area, whichever is greater. In addition:

i. if natural means provide adequate ventilation, then a mechanical ventilation system is not necessary;

ii. if a mechanical system does not run continuously, then it must activate when gas detectors indicate the presence of 1 percent or more of combustible gas by volume; and

iii. if discharges from a mechanical ventilation system may be hazardous, the drilling fluid-handling area must be maintained at a negative pressure. The negative pressure area must be protected by using at least one of the following: a pressure-sensitive alarm, open-door alarms on each access to the area, automatic door-closing devices, air locks, or other devices approved by the district manager;

b. gas detectors and alarms except in open areas where adequate ventilation is provided by natural means.

Gas detectors must be tested and recalibrated quarterly. No more than 90 days may elapse between tests;

c. explosion-proof or pressurized electrical equipment to prevent the ignition of explosive gases. Where air is used for pressuring equipment, the air intake must be located outside of and as far as practicable from hazardous areas; and

d. alarms that activate when the mechanical ventilation system fails.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 40:

Subpart 4. Statewide Order No. 29-B-a

Chapter 11. Required Use of Storm Chokes

§1101. Scope

A. Order establishing rules and regulations concerning the required use of storm chokes to prevent blowouts or uncontrolled flow in the case of damage to surface equipment.

AUTHORITY NOTE: Promulgated in accordance with Act 157 of the Legislature of 1940.

HISTORICAL NOTE: Adopted by the Department of Conservation, March 15, 1946, amended March 1, 1961, amended and promulgated by the Department of Natural Resources, Office of Conservation, LR 20:1127 (October 1994), LR 40:

§1103. Applicability

A. All wells capable of flow with a surface pressure in excess of 100 pounds, falling within the following categories, shall be equipped with storm chokes:

1. any locations inaccessible during periods of storm and/or floods, including spillways;
2. located in bodies of water being actively navigated;
3. located in wildlife refuges and/or game preserves;
4. located within 660 feet of railroads, ship channels, and other actively navigated bodies of water;
5. located within 660 feet of state and federal highways in southeast Louisiana, in that area east of a north-south line drawn through New Iberia and south of an east-west line through Opelousas;
6. located within 660 feet of state and federal highways in northeast Louisiana, in that area bounded on the west by the Ouachita River, on the north by the Arkansas-Louisiana line, on the east by the Mississippi River, and on the south by the Black and Red Rivers;
7. located within 660 feet of the following highways:

a. U.S. Highway 71 between Alexandria and Krotz Springs;

b. U.S. Highway 190 between Opelousas and Krotz Springs;

c. U.S. Highway 90 between Lake Charles and the Sabine River;

8. located within the corporate limits of any city, town, village, or other municipality.

AUTHORITY NOTE: Promulgated in accordance with Act 157 of the Legislature of 1940.

HISTORICAL NOTE: Adopted by the Department of Conservation, March 15, 1946, amended March 1, 1961, amended and promulgated by Department of Natural Resources, Office of Conservation, LR 20:1128 (October 1994), LR 40:

§1104. General Requirements for Storm Choke Use at Water Locations

A. This Section only applies to oil and gas wells at water locations.

B. A subsurface safety valve (SSSV) shall be designed, installed, used, maintained, and tested to ensure reliable operation.

1. The device shall be installed at a depth of 100 feet or more below the seafloor within 2 days after production is established.
2. Until a SSSV is installed, the well shall be attended in the immediate vicinity so that emergency actions may be taken while the well is open to flow. During testing and inspection procedures, the well shall not be left unattended while open to production unless a properly operating subsurface-safety device has been installed in the well.
3. The well shall not be open to flow while the SSSV is removed, except when flowing of the well is necessary for a particular operation such as cutting paraffin, bailing sand, or similar operations.
4. All SSSV's must be inspected, installed, used, maintained, and tested in accordance with American Petroleum Institute recommended practice 14B, recommended practice for design, installation, repair, and operation of subsurface safety valve systems.

C. Temporary Removal for Routine Operations

1. Each wireline or pumpdown-retrievable SSSV may be removed, without further authorization or notice, for a routine operation which does not require the approval of Form DM-4R.
2. The well shall be identified by a sign on the wellhead stating that the SSSV has been removed. If the master valve is open, a trained person shall be in the immediate vicinity of the well to attend the well so that emergency actions may be taken, if necessary.
3. A platform well shall be monitored, but a person need not remain in the well-bay area continuously if the master valve is closed. If the well is on a satellite structure, it must be attended or a pump-through plug installed in the tubing at least 100 feet below the mud line and the master valve closed, unless otherwise approved by the district manager.
4. Each operator shall maintain records indicating the date a SSSV is removed, the reason for its removal, and the date it is reinstalled

D. Emergency Action. In the event of an emergency, such as an impending storm, any well not equipped with a subsurface safety device and which is capable of natural flow shall have the device properly installed as soon as possible with due consideration being given to personnel safety.

E. Design and Operation

1. All SSSVs must be inspected, installed, maintained, and tested in accordance with API RP 14B, recommended practice for design, installation, repair, and operation of subsurface safety valve systems.
2. Testing requirements. Each SSSV installed in a well shall be removed, inspected, and repaired or adjusted, as necessary, and reinstalled or replaced at intervals not exceeding 6 months for those valves not installed in a landing nipple and 12 months for those valves installed in a landing nipple.
3. Records must be retained for a period of 2 years for each safety device installed.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 40:

§1105. Waivers

A. Onshore Wells. Where the use of storm chokes would unduly interfere with normal operation of a well, the district manager may, upon submission of pertinent data, in writing, waive the requirements of this order.

B. Offshore Wells

1. The district manager, upon submission of pertinent data, in writing explaining the efforts made to overcome the particular difficulties encountered, may waive the use of a subsurface safety valve under the following circumstances, and may, in his discretion, require in lieu thereof a surface safety valve:

a. where sand is produced to such an extent or in such a manner as to tend to plug the tubing or make inoperative the subsurface safety valve;

b. when the flowing pressure of the well is in excess of 100 psi but is inadequate to activate the subsurface safety valve;

c. where flow rate fluctuations or water production difficulties are so severe that the subsurface safety valve would prevent the well from producing at its allowable rate;

d. where mechanical well conditions do not permit the installation of a subsurface safety valve;

e. in such other cases as the district manager may deem necessary to grant an exception.

AUTHORITY NOTE: Promulgated in accordance with Act 157 of the Legislature of 1940.

HISTORICAL NOTE: Adopted by the Department of Conservation, March 1, 1961, amended March 15, 1961, amended and promulgated by Department of Natural Resources, Office of Conservation, LR 20:1128 (October 1994), LR 40:

James H. Welsh
Commissioner

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